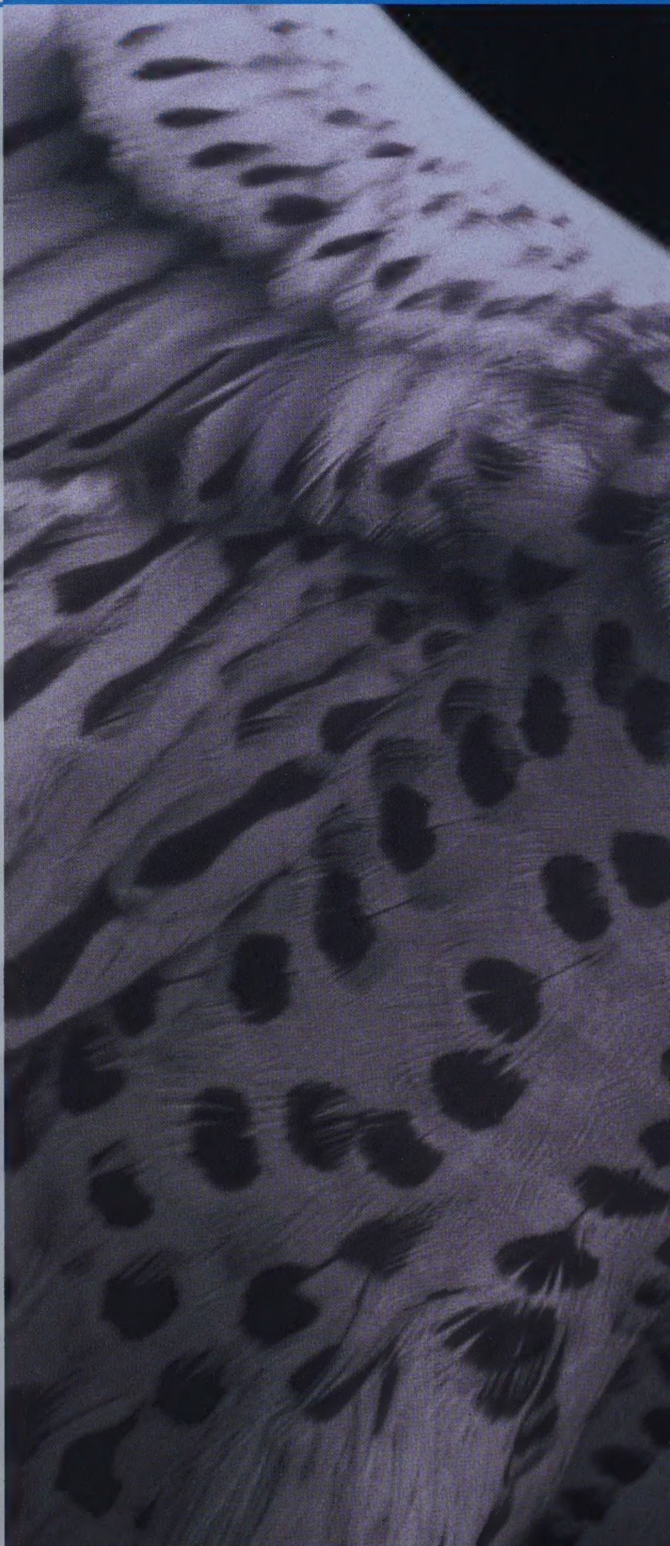
# HAWK OIL

TURNING
OPPORTUNITY
INTO **VALUE**

2001 ANNUAL REPORT

# 2001

**Hawk Oil Inc. is an emerging junior oil and gas exploration and production Company operating in Western Canada and headquartered in Calgary, Alberta.**



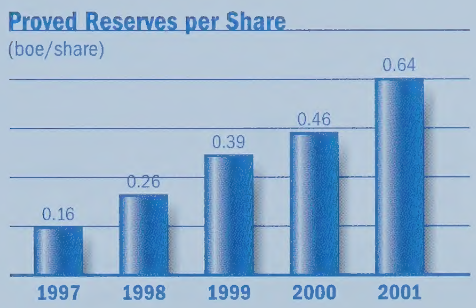
## CORPORATE PROFILE

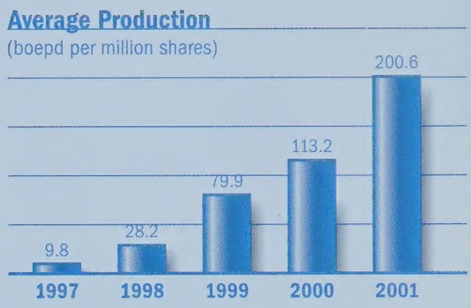
HAWK was incorporated as a private company in 1996 and completed its initial public offering in 1997. Its shares are listed on the Canadian Venture Exchange (CDNX) under the symbol HWK.A.

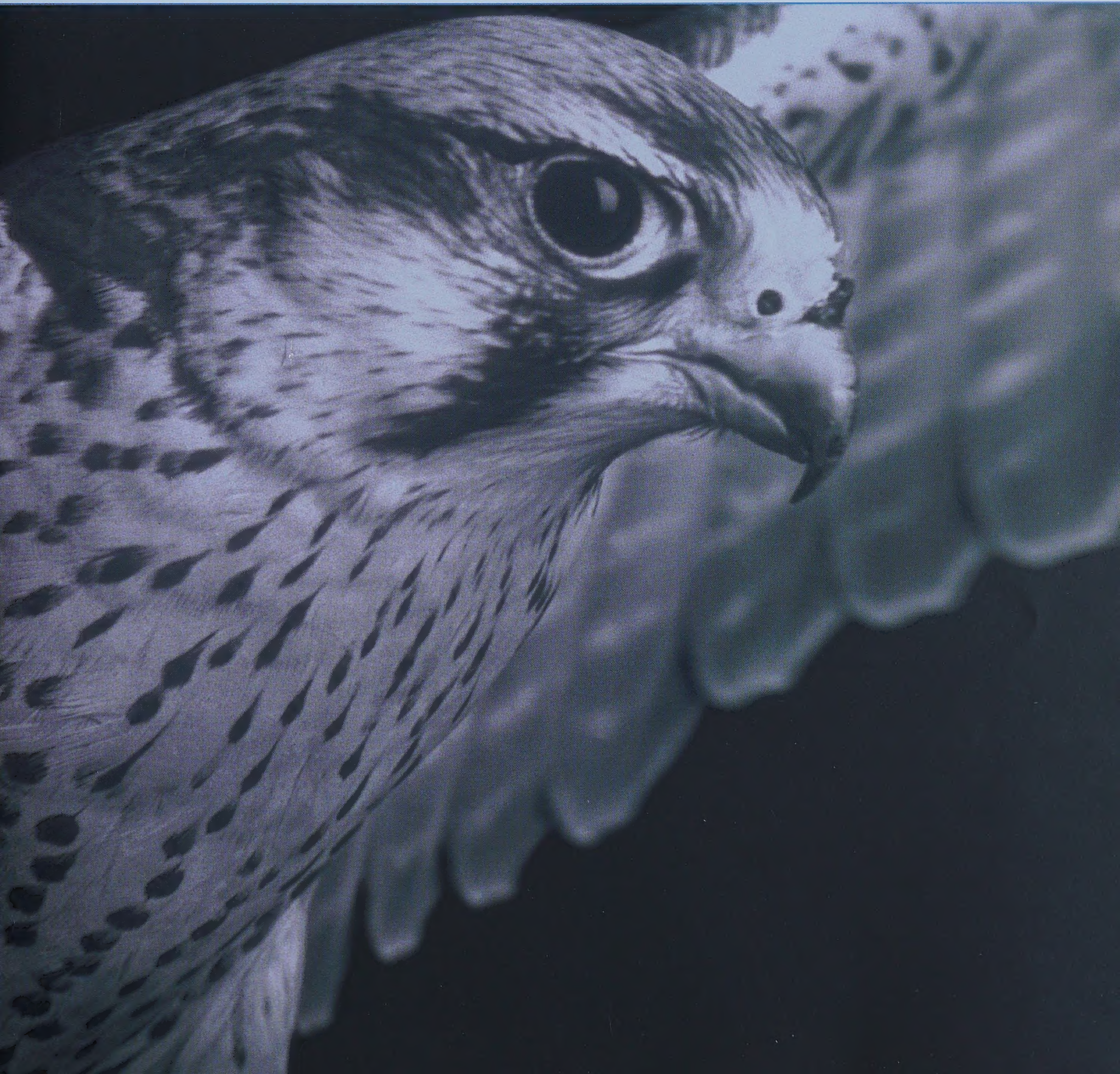
In 2001, Hawk experienced its fifth consecutive year of significant growth in reserves, production and cash flow. The Company continues to maintain a large portfolio of low-to-medium risk, internally-generated exploration and development plays. Hawk operates the vast majority of its production and strives to minimize operating, finding and onstream costs. The Company is strategically positioned with a strong balance sheet, excellent cash flow and earnings, and a solid management team to take advantage of growth opportunities.

## CREATING SHAREHOLDER VALUE

Since Hawk Oil began trading in 1997, the company has added production and reserves on a per share basis, mainly through the drill bit and internally-generated prospects.



# 2001 HIGHLIGHTS

| FINANCIAL | 2001 | 2000 | %Change |
|---|---|---|---|
| Gross production revenue | **$ 14,368,174** | $ 11,168,102 | 29 |
| Cash flow | **$ 7,444,560** | $ 6,878,810 | 8 |
| Earnings | **$ 3,198,235** | $ 3,382,952 | (5) |
| Capital expenditures | **$ 11,928,323** | $ 9,846,231 | 21 |
| Working capital deficiency | **$ (1,548,918)** | $ (666,491) | 132 |
| Bank debt | **$ 4,150,000** | $ 4,709,250 | (12) |
| Shares outstanding at year end | | | |
| Class A | **7,804,016** | 5,369,533 | |
| Class B | **–** | 712,752 | |
| **OPERATING** | | | |
| Average production | | | |
| Crude oil and NGLs (bbls/day) | **776** | 372 | 109 |
| Natural gas (mcf/day) | **4,735** | 3,020 | 57 |
| Oil equivalent (boepd) (6:1) | **1,565** | 878 | 78 |
| Exit production (4Q average) | | | |
| Crude oil and NGLs (bbls/day) | **865** | 604 | 43 |
| Natural gas (mcf/day) | **7,755** | 3,981 | 95 |
| Oil equivalent (boe/day) (6:1) | **2,158** | 1,268 | 70 |
| Average selling prices | | | |
| Oil ($/bbl) | **22.04** | 34.93 | (37) |
| Natural gas ($/mcf) | **4.58** | 5.83 | (21) |
| Reserves (proven) | | | |
| Oil and NGLs (mbbls) | **3,240** | 2,540 | 28 |
| Natural gas (mmcf) | **10,566** | 6,050 | 75 |
| Barrels of oil equivalent (mboe at 6:1) | **5,001** | 3,548 | 41 |
| Reserve value (12% DCF, $M) | **44,200** | 33,600 | 32 |
| Reserves (proven and probable) | | | |
| Oil and NGLs (mbbls) | **4,667** | 3,880 | 20 |
| Natural gas (mmcf) | **13,280** | 8,010 | 66 |
| Barrels of oil equivalent (mboe at 6:1) | **6,880** | 5,215 | 32 |
| Reserve value (12% DCF, $M) | **56,500** | 44,800 | 26 |
| Undeveloped land (acres) | | | |
| Gross | **19,375** | 28,017 | (31) |
| Net | **16,836** | 22,477 | (25) |
| Wells drilled | | | |
| Gross | **33** | 16 | 106 |
| Net | **30.3** | 15.8 | 92 |
| Success rate | **85%** | 75% | |

# PRESIDENT'S MESSAGE

*Since Hawk's inception in 1997, the Company has demonstrated consistent and profitable growth, year after year, throughout the commodity price cycle.*

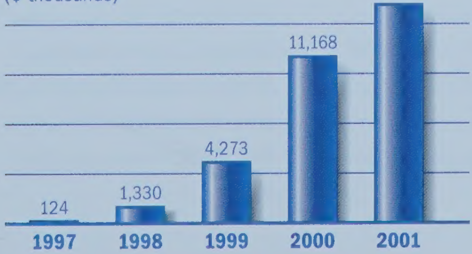
In 2001, Hawk Oil achieved a fifth consecutive year of significant reserve, production and cash flow growth. The Company's 2001 highlights include:

- Drilled 33 (30.4 net) wells, 35 percent of which were classified as exploration, resulting in 28 (25.7 net) producers for an overall success rate of 85 percent.
- Achieved a finding and development cost of $4.92 per boe on a proved reserve basis.
- Increased average daily production over 2000 by 78 percent to 1,565 boe per day.
- Increased diluted cash flow per share by 9 percent to $0.93.
- Increased net asset value by 32 percent to $47.4 million despite a sharply reduced price forecast.

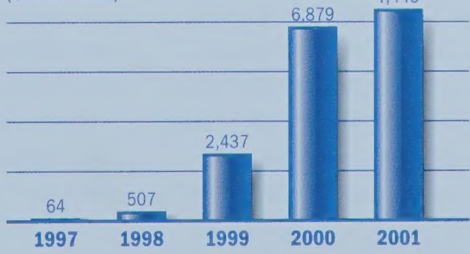
**Erik DeWiel,** *Vice President Land and Business Development* **Dave Bonnar,** *Senior Geologist* **Steve Fitzmaurice,** *President and Chief Executive Officer* **Randy Deobald,** *Vice President Exploration*

- Replaced 2001 production by 355 percent on a proved reserve basis.
- Sold all interests in southeast Saskatchewan for an attractive price of $5.0 million ($25,000 per producing boe).

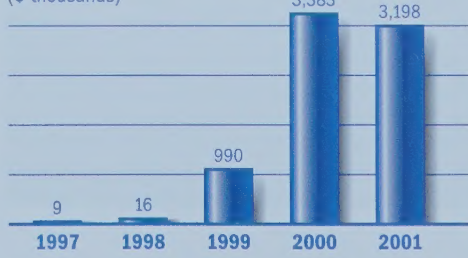
**Net Revenue**
($ thousands)




**Net Cash Flow**
($ thousands)




**Net Earnings**
($ thousands)



## GROWTH STRATEGY

Hawk's growth strategy has remained unchanged since our first day. Simply put, our goal is to profitably grow the Company on a per share basis by focusing on cash flow. We accomplish this by avoiding share dilution and by targeting high netback products in low-cost areas that have year-round access, available infrastructure, moderate drilling depths, affordable land costs and in-house technical knowledge. In 2001, Hawk's strict adherence to this growth strategy enabled the Company to grow profitably on a per share basis. Hawk financed its largest capital program ever through strong cash flow and bank debt. The Company drilled 33 (30.3 net) wells, resulting in 28 (25.7 net) producers that provided the Company with record production and cash flow without the issuance of any additional equity.

To maintain its profitability throughout the price cycle, Hawk strives to be a low cost producer, both in terms of finding and development costs as well as operating and overhead costs. Hawk ensures that its finding and development costs are among the lowest in industry by maintaining strict control over the quality of the technical work that goes into a prospect as well as the capital incurred to turn the prospect into a producer. In addition, Hawk strives to keep operating and overhead costs to an absolute minimum. These low-cost strategies help to maximize cash flow that can be reinvested in the Company.

Another strategy is to limit risk exposure. The Company believes that it is prudent for a junior producer to pursue moderate-risk, moderate-reward prospects rather than high-risk, high-reward prospects. Accordingly, the Company has concentrated on lower-risk areas such as Ranfurly and Epping, resulting in an excellent drilling success rate accompanied by immediate cash flow. As Hawk continues to grow rapidly, we will increase our exposure to higher-risk, higher-reward prospects.

As drilling prospects are developed, Hawk's level of participation in any given play continues to be determined by cost and risk analysis. The Company strives for operatorship and a high working interest in any development or moderate-risk exploration project in order to maintain control over the technical aspects, capital and operating costs. Hawk continues to operate virtually all of its production at an average working interest of approximately 90 percent. On deeper, higher-risk exploration wells, the Company limits its working interest to 25-65 percent.

## INDUSTRY OUTLOOK

The oil and gas industry experienced a great deal of volatility over the past year.

'97 Completed an $8 million financing and drilled 14 (7.7 net) wells, resulting in 9 (4.9 net) producing oil wells. First year proved finding and development cost of $3.59 per boe.

'98 Increased average production by 239 percent to 217 boe per day. Drilling program focused on natural gas in West Edmonton and Vermilion areas. Proved finding and development cost of $4.97 per boe.

'99 Increased production by 185%, cash flow by 381% and earnings by 609%. Also attained a large, balanced inventory of oil and natural gas prospects. Proved finding and development cost was $3.98 per boe.

The beginning of the year saw extremely high commodity prices, coupled with aggressive spending on acquisitions. This was followed by a sharp correction in commodity prices and a corresponding reduction in capital spending.

During the first half of the year – a period of extremely high commodity prices – the intermediate and senior sector of the Canadian oil and gas industry underwent unprecedented consolidation. The majority of these acquisitions were financed entirely with debt. As a result of the sharp correction in commodity prices that occurred later in the year, many of the acquiring companies found themselves with undesirable debt levels. Many of these companies are now selling non-core assets in an effort to strengthen their balance sheets. As a result, in 2002 we find ourselves in a buyers' market for acquisitions.

The medium to long-term fundamentals for the oil and gas industry remain attractive. An improving economy, uncertainty in the Middle East, and reduced capital expenditures by oil and gas industry participants are all contributing factors that should help increase future commodity prices.

## CORPORATE GOVERNANCE

Hawk continues to be very cognizant of the concerns of both regulators and investors regarding the integrity of financial and reserve information reported by the oil and gas industry. Accordingly, Hawk has diligently put in place the necessary accounting and financial reporting systems and controls to ensure that the Company is able to maintain the highest level of accuracy and integrity in all its public disclosure. For this reason, Hawk has elected to utilize two of the largest and most respected accounting and reservoir evaluation firms: PricewaterhouseCoopers LLP and Gilbert Laustsen Jung Associates Limited.

The Canadian Securities Administrators have recently published, in draft form, National Policy 51-101. This policy, which is expected to be implemented in 2003, requires a number of changes in the way oil and gas companies report their reserves, finding and development costs, activities and other financial information. Hawk has attempted to implement as many of these recommendations in this report as possible.

Two of the more significant changes include reporting all boe using the conversion factor of 6 mcf: 1 bbl and the inclusion of all future development capital in the finding and development cost calculation.

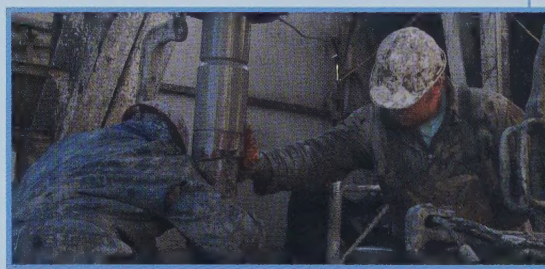
## 2002 OUTLOOK

Since Hawk's inception in 1997, the Company has prudently invested the $8,836,000 it raised through two equity offerings, resulting in a current net asset value for the Company of $47.4 million.

'00 Average production increased to 875 boe per day, while cash flow and earnings increased by 182 percent and 244 percent respectively. Focused on North Epping heavy oil development.

'01 Drilled 33 (30.4 net) wells, and added production and reserves. Achieved finding and development cost of $4.92 per boe (proved), one of lowest in industry. Key natural gas discovery at Birch/Ranfurly.

'02 $17.5 million budget targetting moderate-risk wells in Central Alberta and Lloydminster. Strong balance sheet provides option to participate in acquisitions market. Hawk forecasts 2002 exit rate production of 2,750 boe per day.



We are proud of our growth to date and believe that our operating strategy, financial position and strength of management team will continue to form a strong foundation for further growth in reserves, production and cash flow during 2002.

In 2002, Hawk will use the strength of its balance sheet to take advantage of the acquisitions market. As a result of Hawk's southeast Saskatchewan divesture, the Company is entering 2002 with only $5.3 million in debt drawn against a lending value of $18.3 million. We are currently evaluating both larger property and corporate acquisitions that fit our corporate strategy. Hawk will continue to search for operated, high-interest, under-developed properties that can be acquired at a reasonable cost.

The Company has set a capital budget for 2002 of $17.5 million, which includes drilling 20 wells in our core areas in Central Alberta and Lloydminster, where the Company has demonstrated that it can grow profitably with moderate-risk drilling. Hawk has also allocated funds for an asset acquisition as well as the development of a new gas-prone core area. In this new core area the Company will employ the same strategies that proved successful at Vermilion. In addition, Hawk plans to spend approximately 20 percent of its 2002 budget on deeper, higher-risk gas prospects in western Alberta.

Excluding acquisitions, Hawk is forecasting average production for 2002 of 2,300 boe per day with an exit rate of 2,750 boe per day.

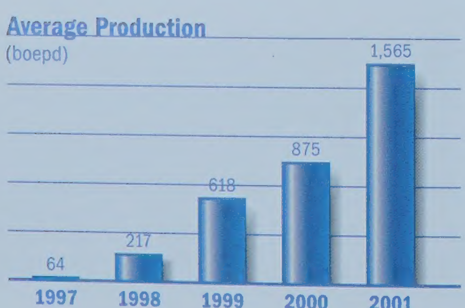
Hawk is well positioned to take advantage of the many excellent opportunities available to grow the Company. We have a strong balance sheet with low debt. We maintain a low cost structure with below average finding and development, operating and G&A costs. The Company will employ these strengths to ensure that Hawk has another successful year in 2002.

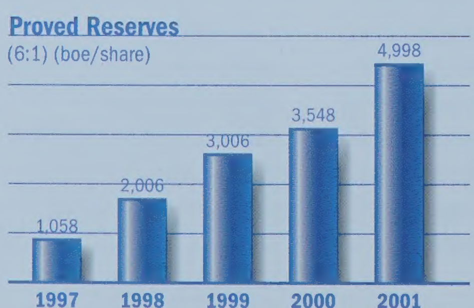

## ACKNOWLEDGMENTS

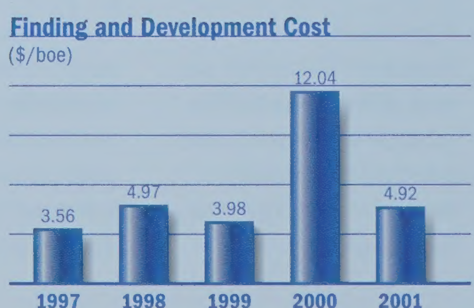
I would like to take this opportunity to thank our shareholders, directors, employees and other stakeholders for their support over the past year.


On behalf of the Board of Directors,

Stephen J. Fitzmaurice
President and Chief Executive Officer
Chairman of the Board
March 22, 2002



# OPERATIONS REVIEW

## Hawk exited 2001 with over 2,000 boe per day, balanced between crude oil and natural gas.

In 2001, the Canadian oil and gas industry experienced strong oil prices in the first eight months followed by a sharp decline in September and continued weakening during the remainder of the year as the North American economy slipped into a recession. The heavy oil market was particularly hard hit as the differential between light and heavy crude oil widened to near historic highs in the fourth quarter. Natural gas prices were at historic highs at the outset of 2001 but declined by 75 percent by September mainly because of an oversupply in the North American market. Late in the year gas prices firmed at the $3.00 per mcf range.

In the past year, the oil and gas industry drilled a record number of wells and faced high land prices. However, 2001 finished on a pessimistic note with most companies curtailing drilling activities as future price concerns dominated.

### INVESTORS RETURN

The sector experienced a resurgence in investor interest in 2001 in the micro to intermediate oil and gas equity markets, which had focused on senior producers in 2000. High commodity prices for the majority of 2001 allowed well managed companies to establish healthy balance sheets and to show significant gains in production. The past year also continued the pattern of consolidation in the oil and gas industry that was established in previous years.

### AGGRESSIVE DRILLING

During the first half of 2001, Hawk initiated a process to maximize shareholder value and to take advantage of the buoyant acquisition market. The Company drilled in excess of twenty development wells, which allowed us to move large proven undeveloped reserves into the more valuable proven producing category. Following completion of an updated engineering report, Hawk initiated a sale procedure in late August. The process was overtaken by events of last fall and the subsequent downturn in the global economy, which had an adverse effect on commodity prices. The bids we received were inadequate and management decided shareholders would be better served by continuing to grow the Company.

Effective October 1, 2001 Hawk sold its Southeast Saskatchewan assets and used the $ 5.0 million received to reduce bank debt to six months cash flow. The transaction greatly increased Hawk's financial flexibility, and has positioned the Company to pursue longer term gas and light oil opportunities in Alberta. Hawk ended the year with a strong balance sheet and a production rate that was double the 2000 exit rate.

During 2001, Hawk continued to focus on maintaining a balanced oil and gas production profile. Returns on heavy oil over the first eight months warranted the drilling of an additional 20 (19.7 net) low risk oil wells in Saskatchewan. This drilling occurred at Epping where Hawk continued to develop a multi-zone oil and gas pool and at Mervin where we drilled a number of delineation wells. In Alberta the Company pursued a variety of natural gas plays, which resulted in a number of new pool discoveries. The most significant of these discoveries occurred in the Birch/Ranfurly area where Hawk built on an exciting find in late 2000.

### INCREASE PRODUCTION

In 2001, Hawk drilled 33 (30.3 net) wells in Alberta and Saskatchewan, and increased average production by 79 percent to 1,565 boe per day compared to 875 boe per day in 2000. Hawk exited 2001 with over 2,000 boe per day and a production mix that averaged 50 percent natural gas and 50 percent oil.

Hawk's average production rate has steadily increased over the years, from 64 boe per day in 1997, to 217 in 1998, 618 in 1999, 875 in 2000 and to 1,565 in 2001. Over the past year, we drilled and cased 14 (13.7 net) wells on our North Epping property, including

13 that were cased as oil wells and one as a gas well. All wells are currently producing. In Southeast Saskatchewan, the Company drilled two (100% WI) horizontal oil wells at Glen Ewen and Bromhead. Hawk drilled one (100% WI) successful gas well at Lac Canard and four (100% WI) at Ranfurly/Birch, Alberta. The Company operated 91 percent of this drilling activity and achieved a success rate of 85 percent.

At December 31, 2001 Hawk's proven reserves totalled 5.0 million boe, which was a 41 percent increase over 2000 and a 355 percent replacement of the Company's 2001 production. Hawk's finding and development cost for 2001 was $4.92 per boe for proven reserves and $5.31 per boe for proven plus probable reserves. Hawk has demonstrated consistent efficiency in its exploration and development activities since the Company was formed in 1997. Our five year average finding and development cost is $5.41 per boe proven and $4.39 per boe proven plus probable.

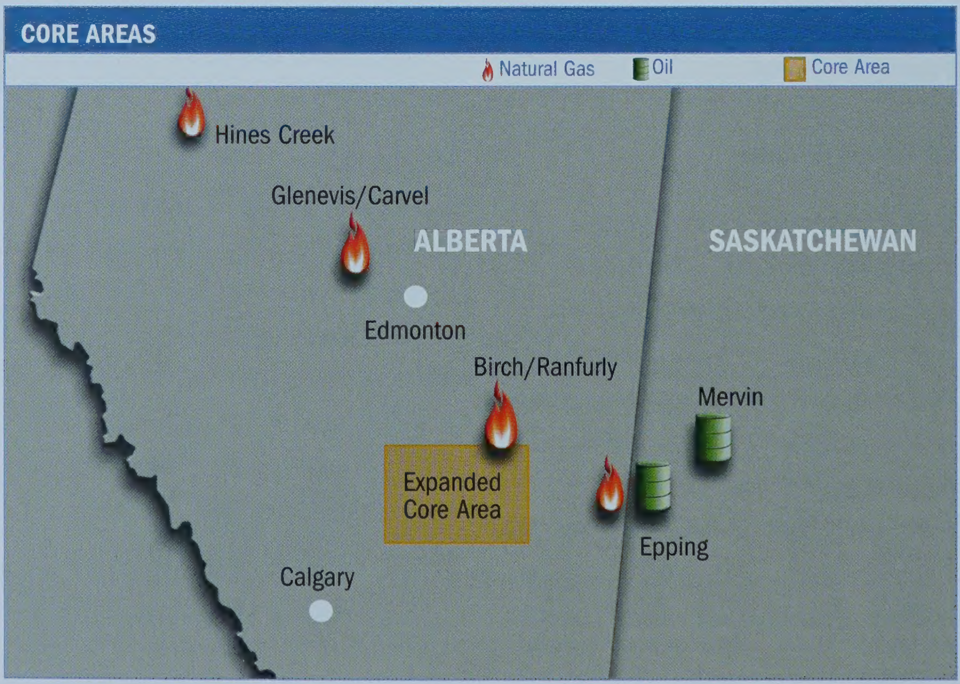
Over the past year, Hawk has consolidated its areas of operation and continues to add longer reserve life prospects.

During 2001, Hawk's land inventory decreased from 42,293 (31,696 net) acres to 33,262 (27,168 net) acres, primarily as a result of the sale of Hawk's Southeast Saskatchewan assets. Of the remaining acreage, 19,375 (16,836 net) acres are undeveloped. Hawk has a 74 percent average working interest in the developed lands and 87 percent in the undeveloped acreage. Going forward the acquisition of a significant undeveloped land base is a clear priority.

## EXPLORATION AND DEVELOPMENT STRATEGY

Hawk's success in 2001 reflects our well established growth strategy, which we have followed since our inception. The Company's exploration and development activity during 2002 will be guided by the following key elements:

- Focus on projects that generate near-term cash flow;
- Explore in areas with low to moderate cost and available infrastructure;
- Explore for pools that can be brought onstream quickly;
- Maintain control over capital and operating costs;
- Concentrate on areas that are well understood by our technical team;
- Pursue internally-generated prospects using sophisticated geophysical technology;
- Maintain high working interests and, wherever possible, operatorship;



- Expand our land base within our core areas, and
- Maintain a large, balanced inventory of exploration, development and acquisition opportunities.

## KEY PROPERTIES

### NORTH EPPING

Hawk's North Epping property, which lies 10 miles south of Lloydminster on the Alberta-Saskatchewan border, was acquired at Crown land sales on an internally-generated prospect. Production in this region is associated with stacked sands of the Mannville Group, all of which display excellent reservoir characteristics. Hawk holds approximately 2,230 (1,998 net) acres of land at North Epping. To date, the Company has drilled 30 wells on the property and re-entered one abandoned well in order to complete a missed pay zone. The only dry hole drilled to date at North Epping was a step-out well to test a separate seismic anomaly. At present, Hawk owns 27 producing oil wells and three producing gas wells on this property, which produce from six different zones that include the Lower Cummings, Lloydminster, General Petroleum (GP), Sparky, McLaren and Colony. Oil quality ranges from 14 degree API in the Lower Cummings to 18 degrees in the McLaren. The presence of economic hydrocarbon accumulations in so many zones offers opportunities for accelerated production through additional drilling.

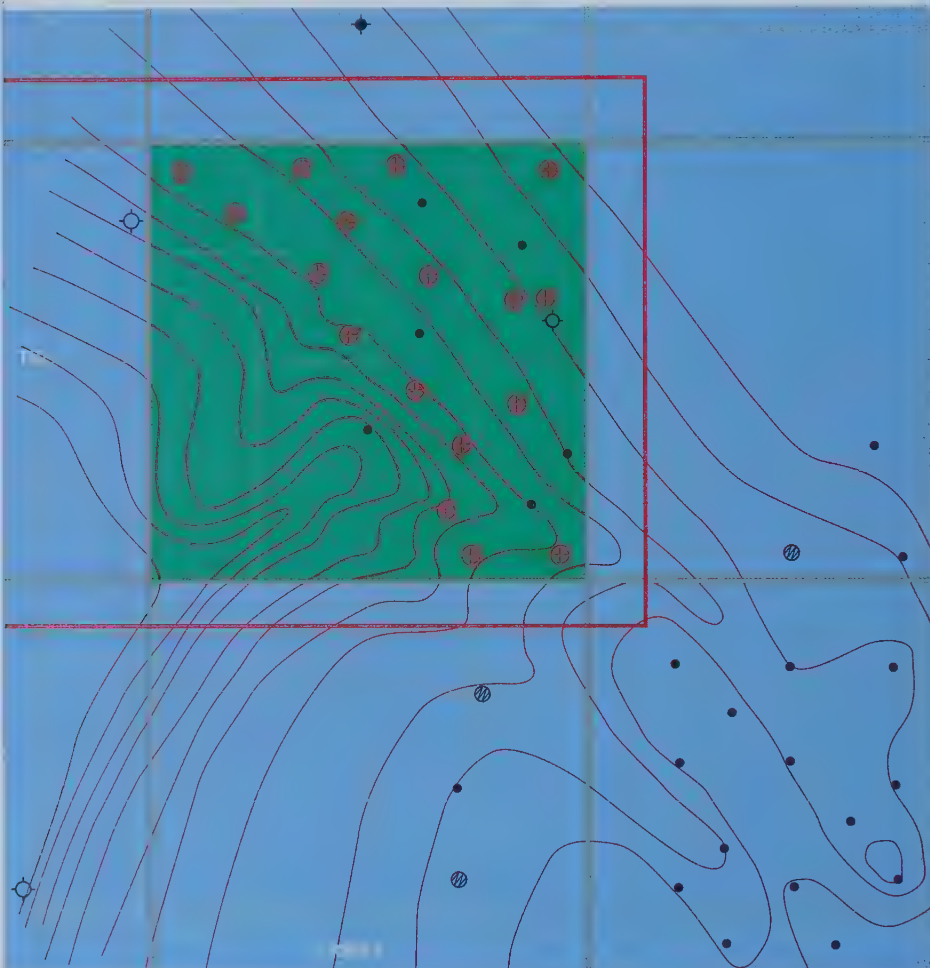
The North Epping property averaged 636 bbls of oil per day and 1.1 mmcf of gas per day in the fourth quarter of 2001. Average production during the year of 726 boe per day was 103 percent higher than the 2000 average of 358 boe per day, and was comprised of 531 bbls of oil and 1.2 mmcf of natural gas. Late in 2001, Hawk drilled a successful multi-zone gas well at Epping which was recently completed and tied in. The well is currently producing 500 mcf per day, a rate that may increase after further testing.

At North Epping, Hawk has eight (100% WI) producing Lower Cummings oil wells, plus three (0.69 net) additional non-operated wells that were drilled in December 2001 and have yet to be completed. There are three (2.23 net) undrilled locations remaining to fully develop the Lower Cummings in this pool. Moving upward in the stratigraphic column, Hawk has 10 (9.97 net) producing oil wells in the Sparky/GP sands in the North Epping pool. There are 11 (10.23 net) undrilled development locations left to fully develop this interval within the pool, as well as several step-out locations. The McLaren interval, which lies above the Sparky/GP, currently produces 18 degree API oil from five


▲ Hawk's North Epping property has become a production and cash flow work horse.

(100% WI) wells. This shallowest of the oil-producing zones is also the least developed. McLaren pay is present in 15 (12.69 net) wells which are currently producing from deeper horizons, but will be recompleted in the future to capture these additional reserves. There are 13 (12.23 net) drilling locations remaining to fully develop this zone. Hawk currently produces three (100% WI) gas wells from different zones on this property at a steady rate of 1.6 mmcf per day.

## MERVIN WASECA STRUCTURE CONTOUR MAP




Map shows structural high over Hawk acreage at Mervin.

### MERVIN

Hawk holds a 100 percent working interest in 1,440 acres of land in the Mervin area which lies approximately 45 miles east of Lloydminster. This acreage was acquired at a Crown land sale on another internally-generated prospect where mapping revealed a Waseca shoreface sand charged with oil that displayed excellent reservoir characteristics. The Hawk acreage lies on a structural high that also has oil pay in the underlying Sparky sand.

Since May 2001, Hawk has drilled and put on production six (100% WI) oil wells, which on average are each capable of producing in excess of 60 bbls per day. These wells have high initial sand production, which often leads to improved oil production in the first year. Proprietary 3D seismic covering the pool indicates that another 16-20 (100% WI) drilling locations remain to fully develop this pool. In addition to the Waseca oil pool, the underlying Sparky sandstone remains untested.

The Mervin property is currently producing approximately 175 bbls per day of 12 degree API oil with water cuts of less than 15 percent. The pool averaged 97 bbls per day in 2001; however, this reflects approximately five months of production. This pool has displayed very encouraging near-term results and we expect significant production gains in 2002.

Hawk has budgeted the drilling of 15 net heavy oil wells in its 2002 capital budget. By the first quarter of 2002, heavy oil differentials narrowed considerably to the Cdn$6-$8 range, which translated into netbacks in the Cdn$15-$20 per barrel range.

Approximately four of the budgeted wells will be in the multi-zone Epping area. An additional 10 wells, targeting both the Waseca and Sparky, are planned for Mervin and one exploratory well will be drilled in the general Lloydminster area.

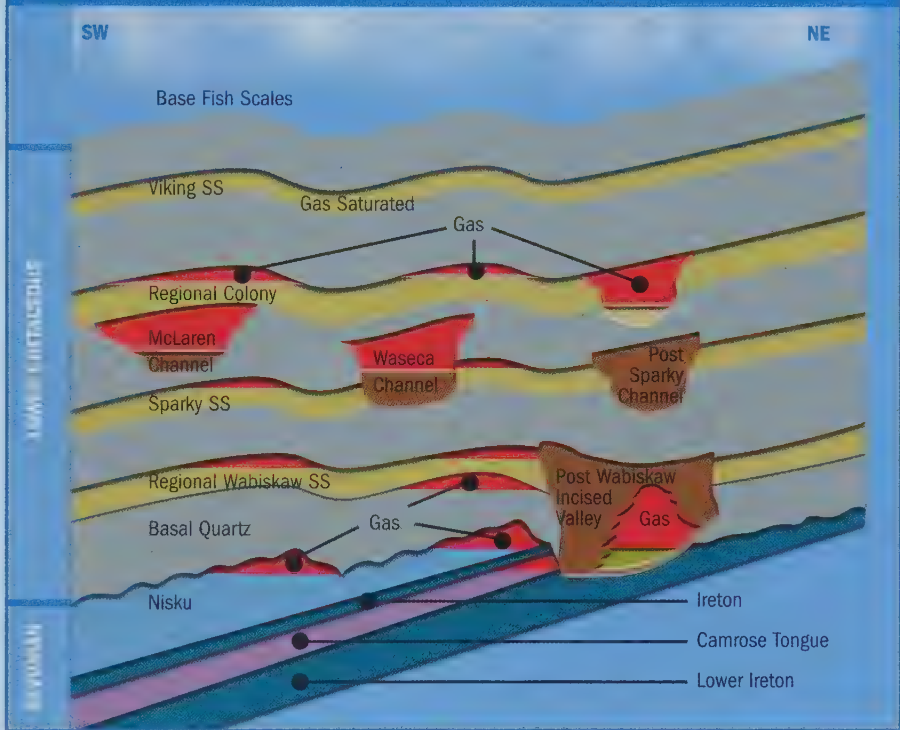
Average field netbacks (revenue less tariffs, royalties and operating costs) for Hawk's 2001 Lloydminster area heavy production were $12.89 per barrel of oil and $2.75 per mcf of natural gas. Operating costs for the year averaged $6.58 per barrel of oil and $0.41 per mcf of natural gas.

## SOUTHEAST SASKATCHEWAN

During 2001, Hawk assessed its inventory of opportunities and decided it was an appropriate time to focus the Company primarily on natural gas and light oil in Alberta and heavy oil in the Lloydminster region. These areas had accounted for Hawk's greatest successes over the past four years. The Company's properties in Southeast Saskatchewan were generally more mature and some had reached the point where operating costs were becoming prohibitive. Consequently, Hawk sold its entire asset base in Southeast Saskatchewan effective October 1, 2001 and immediately applied the proceeds against debt, reducing our debt to cash flow ratio to half a year. This in turn is allowing the Company to participate in the acquisition market being created as numerous larger companies consolidate and rationalize assets.

Hawk produced light oil and minor associated gas from five properties in Southeast Saskatchewan. At Glen Ewen, Bromhead, Queensdale and Rosebank, oil is trapped in Mississippian-aged limestone reservoirs while at Montmartre, oil occurs in Ordovician dolomites. The Company held an average 90 percent working interest in this region. During 2001, Hawk drilled a total of two (100% WI) horizontal oil wells at Glen Ewen and Bromhead. Both wells required modification to existing treatment facilities in order to handle large fluid volumes, but neither procedure was completed before the divestiture.

**BIRCH/RANFURLY STRATIGRAPHIC SCHEMATIC**




▲ Natural gas potential is found in both Cretaceous zones and the Devonian subcrop.

Total net production for 2001 in Southeast Saskatchewan was 154 boe per day versus 164 boe per day in 2000. This decline reflects only nine months of production in the past year due to the sale of the assets in October. The field netback for this production was $21.69 per boe, while operating costs averaged $6.50 per boe.

## BIRCH/RANFURLY

Over the past year, Hawk was very active in an area centered approximately 80 miles east of Edmonton. The majority of this activity took place in the Birch/Ranfurly area which remains a core area for Hawk as the Company continues to acquire land and expand activities. Presently in this region, Hawk holds 9,643 (9,153 net) acres of undeveloped land, which are prospective for natural gas in a number of Cretaceous zones as well as the Devonian subcrop, all at depths less than 800 metres.

During 2001, the Company drilled and cased five natural gas wells in this area, three of which followed up on a significant new pool discovery which was made in late 2000. These wells were drilled into an incised valley

## RANFURLY/ST. PAUL LAND MAP


which had been eroded and filled immediately after regional Wabiskaw deposition. The reservoirs consist of high deliverability, discrete 'channel' sandstones which are encased within a predominantly mud-filled valley. The remaining two wells were Colony discoveries.

The Company's net production in this region averaged 2.68 mmcf per day during 2001 compared with 1.37 mmcf per day in 2000. Presently, production is 5.0 mmcf per day net to Hawk. The average field netback during 2001 for this group of wells was $2.82 per mcf , while operating costs improved to an average of $0.62 per mcf.

The Company is continuing to expand its activities in the plains, west of the fourth meridian. This search is primarily centered on natural gas potential and we will use our production base and knowledge gained at Birch/Ranfurly to increase volumes. Hawk is presently acquiring considerable seismic data and land in this region and expects to define a number of exciting opportunities for drilling later in the second quarter. Hawk has budgeted a total of 17 gas tests in the plains area for 2002, with a minimum of five to be drilled during the first quarter.

▲ Success achieved at Birch/Ranfurly has provided the impetus for expanding this lucrative shallow gas play.

## OPERATIONAL HIGHLIGHTS:

- Increased average daily production by 78 percent to 1,565 boe per day.
- Exited 2001 with production in excess of 2,000 boe per day.
- Drilled 33 (30.3 net) wells, resulting in 28 (25.7 net) producers for an overall success ratio of 85 percent. Ten of these locations were exploration wells.
- Continued trend of low proven finding and development costs with $4.92 per boe for 2001, resulting in a five year average of $5.31 per boe.
- Increased proven reserves by 41 percent to 5.0 million boe.
- Discovered four new gas pools which are contributing to the 5.0 mmcf per day that Hawk produces in the Ranfurly/St. Paul area.
- Delineated a new heavy oil pool with the drilling of six producing oil wells at Mervin, Saskatchewan.
- Received approval for spacing change on Hawk's Mervin property, which increased the number of drilling locations to 16 from the prior six locations.
- Sold all the Southeast Saskatchewan assets in the fourth quarter to position Hawk to take advantage of upcoming acquisition opportunities.

## LOOKING FORWARD

We are proud of the results achieved over the past year and we anticipate continued success in 2002, based on the same growth strategies we have used in the past. The Company is well positioned financially to take advantage of the expected acquisitions market resulting from the recent period of consolidation among senior producers. One of our top priorities going forward is to increase Hawk's net undeveloped land base and this could result in Hawk expanding into areas with deeper drilling targets. In 2002, higher risk, higher reward prospects could account for 15 to 25 percent of Hawk's capital budget.

In 2002, Hawk intends to drill a minimum of 15 (100% WI) wells in the Lloydminster region. These locations will be a mix of exploration and development wells and will capitalize on Hawk's experience as a low cost producer in the area. On the gas side, the Company continues to add land and pursue the types of plays that created the significant growth of the past year. Hawk plans to drill a minimum of 17 high working-interest wells on a variety of seismically defined prospects.

The Company has demonstrated a consistent growth profile in its five year history, primarily through reinvesting cash flow and to a lesser degree through prudent use of bank debt. Hawk will continue to demonstrate consistent growth in 2002 through a combination of drilling and acquisitions that represent value and complement the Company's assets.

## Operations Statistical Review

### DRILLING SUMMARY

During 2001, Hawk participated in the drilling of 33 (30.4 net) wells, 35 percent of which were classified as exploration, resulting in 28 (25.7 net) producers for an overall success rate of 85 percent. Hawk operated 30 of 33 wells.

**2001 DRILLING ACTIVITY BY AREA**

| Property | **Wells Drilled** |
|---|---|
| SE Saskatchewan | **2** |
| Epping, Saskatchewan | **14** |
| Mervin, Saskatchewan | **7** |
| Vermilion, Alberta | **9** |
| West Edmonton, Alberta | **1** |
| Total | **33** |

**DRILLING ACTIVITY**

| Year ended December 31 | **2001** | | 2000 | |
|---|---|---|---|---|
| (number of wells) | **Gross** | **Net** | Gross | Net |
| Oil | **22.0** | **19.7** | 9.0 | 8.8 |
| Natural Gas | **6.0** | **6.0** | 3.0 | 3.0 |
| Dry | **5.0** | **4.7** | 4.0 | 4.0 |
| Total | **33.0** | **30.4** | 16.0 | 15.8 |
| Exploratory | **11.0** | **10.6** | 8.0 | 8.0 |
| Development | **22.0** | **19.8** | 8.0 | 7.8 |
| Average working interest (%) | | **92** | | 99 |

## LAND HOLDINGS

In the fourth quarter of 2001, Hawk sold all of its production and udeveloped land in Southeast Saskatchewan. As a result, the Company's land base decreased from 2000. However, as a junior company, Hawk recognizes the importance of a large land base and has continued to accumulate land in strategic areas. Hawk currently holds approximately 33,262 acres (27,168 net) of land, 19,375 acres (16,836 net) of which are undeveloped.

**LAND HOLDINGS**

| | 2001 | | | 2000 | | |
|---|---|---|---|---|---|---|
| (Acres) | **Gross** | **Net** | **WI%** | Gross | Net | WI% |
| Developed | **13,887** | **10,332** | **74** | 14,276 | 9,219 | 65 |
| Undeveloped | **19,375** | **16,836** | **87** | 28,017 | 22,477 | 80 |
| Total | **33,262** | **27,168** | **82** | 42,293 | 31,696 | 75 |

**UNDEVELOPED LAND HOLDINGS**

| | | 2001 | |
|---|---|---|---|
| (Acres) | **Gross** | **Net** | **WI%** |
| Mervin, Saskatchewan | **398** | **398** | **100** |
| Epping, Saskatchewan | **1,288** | **1,288** | **100** |
| West Central Saskatchewan | **1,403** | **1,403** | **100** |
| Lloydminster, Alberta | **1,280** | **1,280** | **100** |
| West Edmonton, Alberta | **2,163** | **1,554** | **72** |
| Hines Creek, Alberta | **1,280** | **1,280** | **100** |
| Vermilion, Alberta | **5,060** | **4,730** | **93** |
| Ranfurly, Alberta | **4,583** | **4,423** | **97** |
| Bear Flat. B.C. | **1,920** | **480** | **25** |
| Total | **19,375** | **16,836** | **87** |

## PRODUCTION SUMMARY

During 2001, the Company continued to build a production base through drilling in its core areas of Vermilion and Epping. Hawk also added a new core production area in Mervin, Saskatchewan. Effective October 1, 2001, the Company sold its interest in Southeast Saskatchewan, which had associated production of 200 boe per day. Consequently, Hawk's average production for 2001 was 1,565 boe per day, while fourth quarter production averaged 2,158 boe per day. The increase in the fourth quarter production is attributable to successful drilling programs in Vermilion, Epping and Mervin.

### 2001 AVERAGE PRODUCTION SUMMARY

| Property | Working Interest (%) | Net Gas Production (mcfd) | Net Oil Production (bopd) | Net Total Production (boepd) |
|---|---|---|---|---|
| Hines Creek gas | 100 | 565 | – | 94 |
| Vermilion gas | 76 | 2,678 | – | 446 |
| West Edmonton | 100 | 277 | 2 | 48 |
| Epping gas | 100 | 1,169 | 2 | 195 |
| Epping oil | 100 | – | 531 | 531 |
| Mervin oil | 100 | – | 97 | 97 |
| SE Saskatchewan | 90 | 46 | 146 | 154 |
| Total | | 4,735 | 776 | 1,565 |

### 2001 FOURTH QUARTER AVERAGE PRODUCTION SUMMARY

| Property | Working Interest (%) | Net Gas Production (mcfd) | Net Oil Production (bopd) | Net Total Production (boepd) |
|---|---|---|---|---|
| Hines gas | 100 | 550 | – | 92 |
| Vermilion gas | 84 | 5,970 | – | 995 |
| West Edmonton | 100 | 150 | 1 | 26 |
| Epping gas | 100 | 1,085 | – | 181 |
| Epping oil | 100 | – | 636 | 636 |
| Mervin oil | 100 | – | 228 | 228 |
| SE Saskatchewan | – | – | – | |
| Total | – | 7,755 | 865 | 2,158 |

## RESERVE SUMMARY

Hawk's reserves have been evaluated effective January 1, 2002 by the independent engineering firm of Gilbert Laustsen Jung Associates Ltd. (GLJ). The preparation date of the information provided to GLJ was October 1, 2001. The evaluation of net present value is stated net of royalties, operating costs and future development costs and is stated prior to any provision for income tax, abandonment, overhead and interest costs. Probable reserve values and volumes have been reduced by 50 percent to account for risk. The following tables summarize the findings of the GLJ report on an escalated price basis:

**RESERVE SUMMARY**

| | Remaining Reserves | | | Net Present Value Before Income Tax Discounted At | | | |
|---|---|---|---|---|---|---|---|
| | Crude Oil (mmbls) | Natural Gas (mmcf) | BOE (mboe) | 0% ($mm) | 10% ($mm) | 12% ($mm) | 15% ($mm) |
| Proved producing | 1,466 | 9,730 | 3,088 | 45.2 | 32.8 | 31.2 | 29.2 |
| Total proved | 3,236 | 10,570 | 4,998 | 70.4 | 47.0 | 44.2 | 40.6 |
| Probable | 1,431 | 2,710 | 1,883 | 26.5 | 13.6 | 12.3 | 10.7 |
| Proved plus risked probable | 3,952 | 11,925 | 5,940 | 83.7 | 53.8 | 50.4 | 46.0 |

The Company's proved reserve life index is 8.8 years and its proved plus half probable reserve life index is 10.4 years.

## PRICE FORECASTS

The estimate of net present value is based upon the following price forecast for crude oil and natural gas which was used in the GLJ Reserve Report.

**PRICE FORECASTS**

| | | Oil | | Natural Gas |
|---|---|---|---|---|
| | WTI at Cushing Oklahoma $US/bbl | Light Crude at Edmonton $CDN/bbl | Heavy Crude (12° API) at Hardistry $CDN/bbl | AECO-C Spot $CDN/mmbtu |
| 2002 | 20.00 | 30.75 | 16.75 | 4.30 |
| 2003 | 21.00 | 31.25 | 17.50 | 4.65 |
| 2004 | 21.00 | 30.50 | 19.50 | 4.70 |
| 2005 | 21.00 | 29.50 | 19.25 | 4.70 |

**RESERVE RECONCILIATION**

| | Oil (mbbls) | | | Natural Gas (mmcf) | | |
|---|---|---|---|---|---|---|
| | Proven | Probable | Total | Proven | Probable | Total |
| December 31, 2000 | 2,540 | 1,340 | 3,880 | 6,050 | 1,960 | 8,010 |
| Discoveries and extensions | 1,289 | 404 | 1,693 | 6,275 | 1,456 | 7,731 |
| Divestitures | (466) | (385) | (851) | (147) | (46) | (193) |
| Production | (283) | – | (283) | (1,728) | – | (1728) |
| Revisions of prior estimates | 156 | 72 | 228 | 120 | (660) | (540) |
| December 31, 2001 | 3,236 | 1,431 | 4,667 | 10,570 | 2,710 | 13,280 |

The above table outlines the changes in Hawk's gross reserves since December 31, 2000. Fully 100 percent of the reserve additions originated from drilling.

**FINDING AND DEVELOPMENT COSTS**

| | **2001** | 2000 | Since Inception (1997-2000) |
|---|---|---|---|
| Exploration and development costs incurred | **7,397** | 9,846 | 31,026 |
| Estimated future development costs relating to proved reserves | **2,567** | 4,223 | 2,567 |
| Proved reserves added (mboe) | **2,025** | 1,171 | 5,635 |
| Proved finding and development costs ($/boe) | **4.92** | 12.04 | 5.41 |
| Exploration and development costs incurred | **7,397** | 9,846 | 31,026 |
| Estimated future development costs relating to proved and probable reserves | **4,455** | 7,431 | 4,455 |
| Proved and probable reserves added (mboe) | **2,233** | 1,374 | 8,084 |
| Proved and probable finding and development costs ($/boe) | **5.31** | 12.57 | 4.39 |

In 2001, Hawk was successful at adding new reserves with a net drilling success rate of 85 percent and a proved drilling, finding and development cost of only $4.92 per boe. This figure, coupled with Hawk's proved finding and development cost since inception (1997) of $5.41 per boe, placed Hawk amongst the best in the industry at adding new low cost reserves.

This year, Hawk adopted the standard recommended by the Canadian Securities Administrators in Policy 51-101 for calculating finding and development costs. Under this method, all future undeveloped reserves with their associated future development costs are included in the finding and development cost calculation.

## RECYCLE RATIO

The recycle ratio provides a measure of a company's ability to sustain growth. It is calculated by taking the Company's corporate cash flow netback on a boe basis and dividing it by the proved finding and development cost. For 2001, this was $13.03 per boe divided by $4.92 per boe, resulting in a recycle ratio of 2.65 times.

## FINANCIAL SUMMARY

The operating results for the 2001 calendar year were as follows:

**CASH FLOW FROM OPERATIONS (DOLLARS)**

| Year ended December 31 | 2001 | 2000 |
|---|---|---|
| Petroleum and natural gas revenues | **14,368,174** | 11,168,102 |
| Tariffs | **271,455** | 230,254 |
| Royalties and mineral taxes | **2,314,360** | 1,810,969 |
| Production expenses | **3,005,041** | 1,557,547 |
| General and administrative expenses | **746,648** | 275,634 |
| Interest expenses | **373,065** | 287,288 |
| Current taxes | **213,045** | 127,600 |
| Cash flow | **7,444,560** | 6,878,810 |
| Daily production volume (boe) | **1,565** | 878 |
| Sales price | **25.15** | 34.85 |
| Tariffs | **0.48** | 0.72 |
| Royalties and mineral taxes | **4.05** | 5.65 |
| Production expenses | **5.26** | 4.86 |
| Field netback per boe | **15.36** | 23.62 |
| General and administrative expenses | **1.31** | 0.86 |
| Interest expenses | **0.65** | 0.90 |
| Current taxes | **0.37** | 0.40 |
| Total company netback per boe | **13.03** | 21.46 |

**FIELD NETBACK BY PRODUCT TYPE ($)**

| Year ended December 31 | Oil (bbl) | Gas (mcf) | Total |
|---|---|---|---|
| Petroleum and natural gas revenues | 6,456,123 | 7,912,051 | 14,368,174 |
| Tariffs | – | 271,455 | 271,455 |
| Royalties and mineral taxes | 622,104 | 1,692,256 | 2,314,360 |
| Production expenses | 1,872,773 | 1,132,268 | 3,005,041 |
| Cash flow | 3,961,246 | 4,816,072 | 8,777,318 |
| | | | |
| Daily production volume per day (bbl or mcf) | 776 | 4,735 | |
| Sales price | 22.79 | 4.58 | |
| Tariffs | – | 0.16 | |
| Royalties and mineral taxes | 2.20 | 0.98 | |
| Production expenses | 6.61 | 0.66 | |
| Field netback per unit volume | 13.98 | 2.78 | |

## PETROLEUM AND NATURAL GAS REVENUE

In 2001, the Company's total revenue increased 29 percent over 2000. The higher revenue resulted from a 78 percent increase in production, offset by a 28 percent decrease in average realized selling prices.

Daily average production in 2001 increased to 1,565 boe per day from 878 boe per day in 2000. All of the production growth was through the drill bit during Hawk's successful 2001 drilling program.

World oil prices declined in 2001 from the levels reached in 2000, reflecting weakening demand as the economy slowed. Markets for Canadian heavy oil weakened even more than those for lighter crude oil. Prices for Canadian natural gas experienced considerable volatility during the year, reaching a maximum of $10.91 per mcf during the first quarter, and falling to $3.30 per mcf by the fourth quarter. Hawk received an average oil price of $22.79 per bbl and an average gas price of $4.58 per mcf. These figures are less than the prices received in 2000, which averaged $34.93 per bbl and $5.83 per mcf.

## ROYALTIES AND MINERAL TAXES

Royalties and Mineral Tax expenses, net of ARTC, increased in 2001 to $2,314,360 from $1,810,969 in 2000, reflecting the increased production which more than offset a decrease in the royalty rate. Hawk's overall royalty rate decreased slightly in 2001 to 16.1 percent from 16.6 percent in 2000.

## PRODUCTION EXPENSE

In 2001, production expenses increased to $3,005,041 from $1,557,547 in 2000. On a per boe basis the rate increased to $5.26 from $4.86 in 2000. This increase is attributable to a larger portion of production originating from Hawk's heavy oil areas which have higher production expenses.

## GENERAL AND ADMINISTRATIVE EXPENSES

During 2001, Hawk had general and administrative expenses of $746,648 or $1.31 per boe. In 2000, the Company had general and administrative expenses of $275,634 and also capitalized $427,254 in overhead-related costs to petroleum and natural gas properties and equipment for a total overhead cost of $702,888. In 2001, Hawk opted not to capitalize any general and administrative expense to better reflect its true overhead expense.

## INTEREST EXPENSE

The Company incurred interest expense of $373,065 in 2001 which is an increase over the $287,288 incurred during 2000. The increase is attributable to the increased bank debt the Company used in 2001 to support its large drilling program.

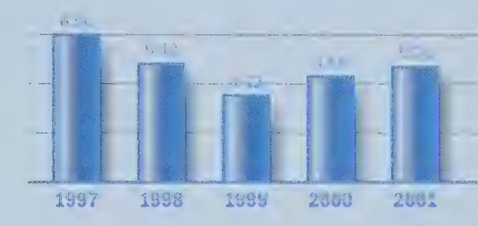
## CURRENT TAXES

In 2001, the Company accrued tax of $213,045 verses $127,600 in 2000. The 2001 tax expense is comprised of $139,622 in federal tax, $61,102 in provincial tax payable to the governments of Alberta and Saskatchewan, and a Large Corporation Tax of $12,321. The Company qualified for the Large Corporation Tax in 2001 as Hawk's capital assets exceeded $10,000,000. In 2001, Hawk's tax pools sheltered most, but not all the strong cash flow generated by the Company's assets. At December 31, 2001, Hawk had approximately $8,475,682 in tax pools available to offset the payment of current taxes on future income comprised of:

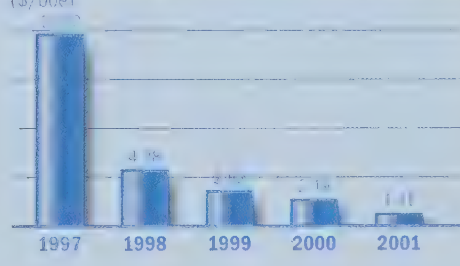
| | |
|---|---|
| Canadian Development Expenses (CDE) | $ 5,115,278 |
| Canadian Oil and Gas Property Expenses (COGPE) | – |
| Undepreciated Capital Cost (UCC) | 3,360,404 |
| | $ 8,475,682 |

## LOW COST PRODUCER

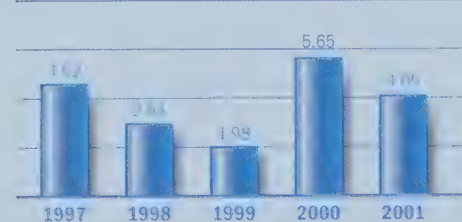
**Production Expenses**
($/boe)




**Gross General and Administrative Expenses**
($/boe)




**Royalties and Mineral Taxes**
($/boe)



## CAPITAL EXPENDITURES

Gross capital expenditures increased from $9,846,231 in 2000 to $11,928,323 in 2001. The gross expenditure in 2001 was offset by the proceeds from the sale of the Southeast Saskatchewan properties of $4,531,750, which resulted in a net 2001 capital expenditure of $7,396,573. The majority of the funds spent were allocated to exploration and development drilling in the Vermilion, Epping and Mervin core areas.

| ($ thousands) | **2001** | 2000 |
|---|---|---|
| Exploration and development | **9,031** | 6,215 |
| Facilities | **2,361** | 1,770 |
| Land | **536** | 1,851 |
| Other | **–** | 10 |
| Total capital expenditures | **11,928** | 9,846 |

## NET ASSET VALUE

At December 31, 2001 Hawk's net asset value was $5.52 per fully diluted share. This is based on the independent evaluation of the Company's proven plus half probable reserves, discounted at 12 percent.

| | **December 31 2001** | December 2000 |
|---|---|---|
| Proved plus 1/2 probable reserves discounted at 12% before tax | **50,400,000** | 39,150,000 |
| Undeveloped acreage ($75/acre) | **1,262,700** | 1,685,775 |
| Debt plus working capital | **(5,698,918)** | (5,375,741) |
| Proceeds from the exercise of stock options and warrants | **1,458,602** | 428,000 |
| Net asset value (fully diluted) | **47,422,384** | 35,888,034 |
| Outstanding common shares | **7,804,016** | 7,732,306 |
| Outstanding stock options | **788,900** | 533,000 |
| Net asset value per fully diluted share | **5.52** | 4.34 |

## DEPLETION AND AMORTIZATION

The Company's depletion and depreciation expenses in 2001 increased to $2,740,512 from $1,448,476 in 2000, primarily reflecting the increases in production over the period. On a unit basis, Hawk's depletion and amortization expense increased slightly from $4.52 per boe to $4.80 per boe.

| | **2001** | | 2000 | |
|---|---|---|---|---|
| | **$** | **$/boe** | $ | $/boe |
| Depletion and amortization | **2,669,134** | **4.67** | 1,410,951 | 4.40 |
| Site restoration | **71,378** | **0.13** | 37,525 | 0.12 |
| Total | **2,740,512** | **4.80** | 1,448,476 | 4.52 |

## WORKING CAPITAL AND CAPITAL REQUIREMENTS

At December 31, 2001 Hawk had a working capital deficiency of $1,548,918 and bank debt of $4,150,000, drawn against a line of credit from the National Bank of Canada of $18,300,000. Hawk will fund its 2002 capital program of $17.5 million through internally generated cash flow and increased bank debt. The Company has no immediate plans to raise additional funds through the equity markets. However, if equity markets for the energy sector improve, then Hawk may raise additional capital through the sale of shares.

## DEBT

On December 31, 2001, the Company's bank debt consisted of a line of credit with the National Bank of Canada for $18,300,000 that bears interest at a rate of prime plus one-quarter percent annually. As of December 31, 2001 Hawk had drawn $4,150,000 against this line of credit.

## BUSINESS RISK

Hawk's forecast results are sensitive to actual realized levels of production as well as commodity prices and exchange rates which can change significantly due to factors beyond the control of the Company. Many business risks are involved in the exploration, development, production and marketing of oil and natural gas including, but not limited to, the uncertainty of finding and producing petroleum and natural gas reserves, commodity prices, interest rate fluctuations, and changes in government environmental, safety and fiscal regulations. The Company manages these risks by employing competent professional staff, following sound operating practices and utilizing cash flow from operations to fund a significant portion of Hawk's capital expenditures.

# Auditors' Report

**TO THE SHAREHOLDERS OF HAWK OIL INC.**

We have audited the balance sheet of Hawk Oil Inc. as at December 31, 2001 and 2000 and the statements of operations and retained earnings and cash flows for the years ended December 31, 2001 and 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and cash flows for the years ended December 31, 2001 and 2000 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants

April 3, 2002
Calgary, Alberta

# Balance Sheet

| December 31 | 2001 | 2000 |
|---|---|---|
| **Assets** | | |
| Current | | |
| Cash | **$ 8,013** | $ – |
| Accounts receivable | **1,738,481** | 2,466,736 |
| Prepaid expenses | **108,209** | 62,649 |
| | **1,854,703** | 2,529,385 |
| Property, plant and equipment (Note 3) | **22,129,145** | 17,401,706 |
| | **$ 23,983,848** | $ 19,931,091 |
| **Liabilities and Shareholders' Equity** | | |
| Current | | |
| Cheques issued in excess of bank balance | **$ –** | $ 28,522 |
| Accounts payable and accrued liabilities | **3,403,621** | 3,167,354 |
| | **3,403,621** | 3,195,876 |
| Bank debt (Note 4) | **4,150,000** | 4,709,250 |
| Provision for site restoration | **139,315** | 67,937 |
| Future income taxes (Note 6) | **5,845,213** | 4,339,400 |
| | **13,538,149** | 12,312,463 |
| Shareholders' equity | | |
| Share capital (Note 5) | **5,142,822** | 5,059,662 |
| Retained earnings | **5,302,877** | 2,558,966 |
| | **10,445,699** | 7,618,628 |
| Commitment (Note 7) | | |
| | **$ 23,983,848** | $ 19,931,091 |

(See accompanying notes.)

Approved on behalf of the Board:

M.H. (Mike) Shaikh
Director

S.J. (Steve) Fitzmaurice
Director

# Statement of Operations and Retained Earnings

| For the year ended December 31 | 2001 | 2000 |
|---|---|---|
| **Revenue** | | |
| Petroleum and natural gas sales, net of royalties | $ 11,780,256 | $ 9,124,703 |
| Other income | 2,103 | 2,176 |
| | 11,782,359 | 9,126,879 |
| **Expenses** | | |
| Operating | 3,005,041 | 1,557,547 |
| General and administrative | 746,648 | 275,634 |
| Interest | 373,065 | 287,288 |
| Depletion and amortization | 2,740,512 | 1,488,476 |
| | 6,865,266 | 3,608,945 |
| Net income before provision for income taxes | 4,917,093 | 5,517,934 |
| Income taxes (Note 6) | | |
| Future | (1,505,813) | (2,007,382) |
| Current and other | (213,045) | (127,600) |
| | (1,718,858) | (2,134,982) |
| Net income | 3,198,235 | 3,382,952 |
| Retained earnings, beginning of year | 2,558,966 | 1,015,147 |
| Adjustment for change in accounting policy (Note 2) | – | (1,839,133) |
| Repurchase of share capital (Note 5(c)) | (454,324) | – |
| Retained earnings, end of year | $ 5,302,877 | $ 2,558,966 |
| Basic net income per Class A shares (Note 1(f)) | $ 0.41 | $ 0.44 |
| Diluted net income per Class A shares (Note 1(f)) | $ 0.40 | $ 0.43 |

(See accompanying notes.)

# Statement of Cash Flow

| For the year ended December 31 | 2001 | 2000 |
|---|---|---|
| Operating activities | | |
| Net income | $ 3,198,235 | $ 3,382,952 |
| Add items not affecting cash | | |
| Depletion and amortization | 2,740,512 | 1,488,476 |
| Future income taxes | 1,505,813 | 2,007,382 |
| Cash flows from operations | 7,444,560 | 6,878,810 |
| Net change in non-cash working capital in operating activities | | |
| Accounts receivable | 728,255 | (1,868,518) |
| Prepaid expenses | (45,560) | (18,587) |
| Accounts payable and accrued liabilities | 675,733 | 1,172,282 |
| | 1,358,428 | (714,823) |
| | 8,802,988 | 6,163,987 |
| Financing activities | | |
| Repayment of bank debt | (559,250) | 3,209,250 |
| Issuance of share capital | 224,466 | – |
| Purchase of share capital for cancellation | (595,630) | (6,915) |
| | (930,414) | 3,202,335 |
| Investing activities | | |
| Expenditures on property, plant and equipment | (11,928,323) | (9,846,231) |
| Proceeds on disposition of petroleum and natural gas assets | 4,531,750 | – |
| Net change in non-cash working capital for investing activities | (439,466) | 524,267 |
| | (7,836,039) | (9,321,964) |
| Increase in cash | 36,535 | 44,358 |
| Cash (indebtedness), beginning of year | (28,522) | (72,880) |
| Cash (indebtedness), end of year | $ 8,013 | $ (28,522) |
| Basic cash flow from operations per Class A share (Note 1(f)) | $ 0.95 | $ 0.89 |
| Diluted cash flow from operations per Class A share (Note 1(f)) | $ 0.93 | $ 0.87 |
| Cash interest paid | $ 370,962 | $ 287,288 |
| Cash income tax paid | $ 197,849 | $ – |

(See accompanying notes.)

# Notes to Financial Statements

**Summary of Significant Accounting Policies**

The financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada. The more significant of these accounting policies are the following:

***a) Petroleum and natural gas properties and equipment***

The Company follows the full cost method of accounting in accordance with the guideline issued by the Canadian Institute of Chartered Accountants whereby all costs associated with the exploration for and development of oil and natural gas reserves are capitalized into a single Canadian cost centre and charged against earnings as set out below. Such costs include land acquisition, geological and geophysical, carrying charges of non-producing properties and costs of drilling both productive and non-productive wells and related overhead charges.

Gains or losses are not recognized upon disposition of oil and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion is provided on costs accumulated in producing cost centres using the unit of production method. For purposes of the depletion calculation, gross proved oil and natural gas reserves, as determined by outside consultants, are converted to a common unit of measure on the basis of their approximate energy content.

The Company periodically reviews the costs associated with unproved properties to determine whether they are likely to be recovered. When costs are not likely to be recovered, the values of these unproved properties are moved to the depletion pool.

The net carrying costs of the Company's oil and natural gas properties in producing cost centres is limited to an estimated recoverable amount. This amount is the aggregate of future net revenues from proved reserves and the costs of undeveloped properties, less future general and administrative costs, financing costs, future site restoration costs and income taxes. Future net revenues have been calculated using prices and cost in effect at the Company's year end without escalation or discounting.

***b) Joint venture accounting***

Substantially all of the Company's petroleum and natural gas exploration and production activities are conducted jointly with others and, accordingly, the accounts reflect only the Company's proportionate interest in such activities.

***c) Property, plant and equipment***

Property, plant and equipment, other than petroleum and natural gas properties and equipments, are recorded at cost. Amortization is provided at 20% annually based on declining balance.

***d) Future removal and site restoration costs***

Estimated future removal and site restoration costs are provided for over the life of the proven reserves on a unit-of-production basis. Costs are estimated by management in consultation with engineers based on current regulations, costs, technology and industry standards. The annual charge is included in depletion and amortization expense and actual future removal and site restoration expenditures are charged to the accumulated provision account as incurred.

***e) Flow-through shares***

The deductions for income tax purposes of resource expenditures related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Future income tax payable is increased and share capital is reduced by the estimated income taxes related to the renounced income tax deductions when resource expenditures are renounced.

***f) Per share data***

Basic per share data per Class A shares is based upon the weighted average number of Class A shares outstanding during the year 7,814,894 (2000 - 7,738,453). Effective July 4, 2001, the Company exercised its option to convert all outstanding Class B shares to Class A shares at a conversion rate of 3.315 Class A shares for each Class B share, resulting in issuance of 2,326,639 additional Class A shares. Earnings and cash flow from operation per share are reported after conversion of Class B shares and restated for prior year. Diluted per share data is based upon the weighted average number of Class A shares outstanding after conversion of Class B shares during the year, and after giving effect to the exercise of the outstanding share options. Total number of shares used to calculate the diluted per share is 7,977,784 (2000 - 8,083,304).

***g) Income taxes***

Income taxes are calculated using the liability method of tax accounting. Temporary differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax liabilities or assets. Future income tax liabilities or assets are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse. Temporary differences arising on acquisitions result in future income tax liabilities or assets.

***h) Stock options***

The consideration received from the option holder upon the exercise of a stock option is credited to share capital at the date of exercise with no compensation expense recognized at the time the stock option is issued or exercised.

***i) Revenue recognition***

Revenues associated with sales of natural gas, natural gas liquids and crude oil owned by the Company are recognized when title passes from the Company to its customer.

***j) Measurement uncertainty***

The amounts recorded for depletion and amortization of property and equipment and the provision for future site restoration are based on estimates. The ceiling test is based on estimates of proved reserves, production rates, gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

## 2. Change in Accounting Policy

***a) Per share amounts***

Effective January 1, 2001, the Company has adopted the use of the treasury stock method versus the imputed earnings method when computing fully diluted earnings per share or fully diluted cash flow per share. There is no impact on basic per share amounts and the reference to "fully-diluted" has been shortened to simply, "diluted". Under the treasury stock method, only "in the money" dilutive shares are included in the weighted average number of shares. It is also assumed that no cash flow or income is earned on the proceeds received from the dilutive shares issued, but rather, the proceeds are used to buy back shares at the weighted average market price experienced during the reporting period. The weighted average number of shares is then reduced by the number of shares acquired.

The effect of this change in accounting policy for the years ended December 31, is shown as follows:

| | New Method | | Old Method | |
|---|---|---|---|---|
| | **2001** | 2000 | **2001** | 2000 |
| Diluted earnings per share | **$ 0.40** | $ 0.43 | **$ 0.38** | $ 0.41 |
| Diluted cash flow from operations per share | **$ 0.93** | $ 0.87 | **$ 0.87** | $ 0.83 |

***b) Income taxes***

Effective January 1, 2000, the Company changed accounting policies to retroactively adopt without restatement of the 1999 financial statements the liability method of accounting for income tax as recommended by the CICA. Under this method, the Company records future income taxes based on the difference between the accounting and income tax value of an asset or liability. The Company adopted the recommendation by recording a decrease in retained earnings of $1,839,133 and an equal increase in future income tax liability.

## 3. Property, Plant and Equipment

| | 2001 | | | 2000 |
|---|---|---|---|---|
| | **Cost** | **Accumulated Depletion and Amortization** | **Net Book Value** | Net Book Value |
| Petroleum and natural gas properties and equipment | **$ 27,326,011** | **$ 5,214,977** | **$ 22,111,034** | $ 17,385,525 |
| Other equipment | **36,312** | **18,201** | **18,111** | 16,181 |
| | **$ 27,362,323** | **$ 5,233,178** | **$ 22,129,145** | $ 17,401,706 |

During 2001, the Company incurred $11,928,323 (2000 - $9,846,231) of capital expenditures related primarily to petroleum and natural gas (P&NG) properties and equipment. The Company also disposed part of the P&NG properties and equipment in southeast Saskatchewan for $4,531,750.

During 2001, the Company did not capitalized any overhead related costs to petroleum and natural gas properties and equipment. However, $437,254 were capitalized during year 2000.

Costs associated with unproven properties excluded from costs subject to depletion for 2001 totalled $1,391,313 (2000 - $3,136,660).

## 4. Bank Debt

The bank debt consists of a revolving reducing demand credit facility with the National Bank of Canada for $18,300,000 at prime plus 1/4% per year. As of December 31, 2001, $4,150,000 (2000 - $4,709,250) was outstanding. Interest incurred during the year was $272,916 (2000 - $275,038). The terms of debt are subject to annual review. Commencing January 28, 2002, the credit facility reduces by $850,000 per month. As collateral security, the Company has pledged a $35 million floating charge debenture against all of its assets and a fixed charge debenture against its major producing petroleum properties. Effective January 1, 2002, the bank debt will be classified as current liability in conformity with an abstract of Emerging Issues Committee of the Canadian Institute of Chartered Accountants.

## 5. Share Capital

***a) Authorized:***

Unlimited number of Class A voting shares
Unlimited number of Class B subordinated voting shares

The Class B shares are convertible into Class A shares at a date to be selected by the Company, between June 30, 2000 and June 30, 2002 and at the option of the Class B shareholder between July 1, 2002 and August 31, 2002. Any Class B shares outstanding on August 31, 2002 shall be automatically converted into Class A shares. The fraction of a Class A share obtained upon conversion of each Class B share will be equal to $10.00 divided by the greater of $1.00 and the current market price of a Class A share. As of July 4, 2001, the Company exercised its option and converted all issued and outstanding Class B shares at 3.315 Class A shares for each Class B share.

***b) Issued:***

| | Number of Shares | Amount |
|---|---|---|
| **Class A shares** | | |
| Balance Class A shares, December 31, 1999 | 5,375,733 | $ 1,414,530 |
| Issuer bid purchases | (6,200) | (6,915) |
| Balance Class A shares, December 31, 2000 | 5,369,533 | 1,407,615 |
| Stock options exercised | 342,444 | 224,466 |
| Conversion from Class B shares | 2,326,639 | 3,596,197 |
| Issuer bid purchases (Note 5(c)) | (234,600) | (85,456) |
| Balance Class A shares, December 31, 2001 | 7,804,016 | $ 5,142,822 |
| | | |
| **Class B shares** | | |
| Balance Class B shares, December 31, 1999 and 2000 | 712,752 | $ 3,652,047 |
| Issuer bid purchases (Note 5(c)) | (10,900) | (55,850) |
| Conversion to Class A shares | (701,852) | (3,596,197) |
| Balance Class B shares, December 31, 2001 | – | – |
| Total share capital, December 31, 2000 | – | $ 5,059,662 |
| Total share capital, December 31, 2001 | – | $ 5,142,822 |

**c) Share purchase**

Pursuant to normal course issuer bid, the Company purchased for cancellation 234,600 Class A shares of the company at various prices from $1.10 to $2.95 during the year for a total cost of $514,062, and 10,900 Class B shares of the company at various prices from $6.75 to $7.50 for a total cost of $81,568.

**d) Share option plan**

The Company has an Employee Incentive Stock Option plan ("Plan") that is administered by the Board of Directors of the Company. All directors, officers, employees and certain consultants are eligible to participate in the Plan. Under the terms of the Plan, the Company has reserved an amount of Class A common shares for options equal to 10% percent of the issued and outstanding shares of the Company. The maximum option term is 5 years and options are non-assignable and non-transferrable.

During year 2001, 334,344 options were granted at an exercise price of $2.00 and 264,000 options were granted at an exercise price of $2.22. Total of 342,444 options were exercised in 2001 as follows:

| Number of Options Exercised | Exercise Price Per Option |
|---|---|
| 294,667 | $ 0.60 |
| 30,000 | $ 0.70 |
| 17,777 | $ 1.50 |

As of year end, number of options outstanding are as follows:

| Number of Options | Options Vested | Exercise Price Per Option | Expiry Date |
|---|---|---|---|
| 15,000 | 15,000 | $ 0.70 | February 19, 2004 |
| 35,556 | 17,777 | $ 1.50 | September 28, 2004 |
| 140,000 | 93,333 | $ 1.00 | June 1, 2005 |
| 334,344 | 111,448 | $ 2.00 | April 10, 2006 |
| 264,000 | – | $ 2.22 | July 19, 2006 |
| 788,900 | | | |

## 6. Future Income Taxes

The difference between the accounting value and the income tax value of the Company's assets and liabilities, which comprise the future tax liability, are as follows:

| | **2001** | 2000 |
|---|---|---|
| Future income tax liabilities | | |
| Property, plant and equipment | **$ 5,908,311** | $ 4,436,005 |
| Future income tax assets | | |
| Site restoration | **(61,326)** | (30,096) |
| Share issue costs | **(1,772)** | (66,509) |
| Net future income tax liability | **$ 5,845,213** | $ 4,339,400 |

The future income tax provision differs from the expected amount computed by applying the Canadian combined Federal and Provincial income tax rate of 44.02% (2000 - 44.3%) as follows:

| | **2001** | 2000 |
|---|---|---|
| Computed "expected" income tax expense | **$ 2,164,504** | $ 2,444,442 |
| Non-deductible crown charges and other expenses | **764,441** | 568,447 |
| Resource allowance | **(1,126,755)** | (854,831) |
| Alberta Royalty Tax Credit | **(67,080)** | (49,112) |
| Other | **(16,252)** | 26,036 |
| | **$ 1,718,858** | $ 2,134,982 |

The combined Federal and Provincial income tax rate reduced from 44.3% to 44.02% due to the reduction in the provincial tax rate. The Company has available for deduction against taxable income share issue costs of approximately $4,000 (2000 - $150,000). In addition, the Company also has tax pools in respect of property, plant and equipment as follows:

| | **2001** | 2000 |
|---|---|---|
| Undepreciated capital cost | **$ 3,360,404** | $ 2,777,498 |
| Cumulative Canadian oil and gas property expenses | **–** | 2,644,133 |
| Cumulative Canadian development expenses | **5,115,278** | 1,966,522 |
| | **$ 8,475,682** | $ 7,388,153 |

## 7. Commitment

The Company is committed to lease payments for occupancy costs and office equipment for the next two years (commitments expire in 2003) as follows:

| | |
|---|---|
| 2002 | $ 59,737 |
| 2003 | $ 3,867 |

## 8. Financial Instruments

The Company's financial instruments that are included in the balance sheet are comprised of cash, accounts receivable, accounts payable and accrued liabilities and bank debt.

***Fair values of financial assets and liabilities***

The fair values of financial instruments that are included in the balance sheet approximate their carrying amount due to the short-term maturity or the floating rate nature of those instruments.

***Credit risk***

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks.

***Interest rate risk***

At December 31, 2001, the Company was exposed to interest rate fluctuations as interest on the Company's bank debt varies with changes in prime rate. A one percent variation in the interest rate would result in a $41,500 variance in the interest expense.

# Corporate Information

## DIRECTORS

***Steve Fitzmaurice, P.Eng****
Chairman of the Board
Calgary, Alberta

***Erik DeWiel, P.Land***
Calgary, Alberta

***Randy Deobald, P.Geol.***
Calgary, Alberta

***John Wright, P.Eng. C.F.A.***+
Calgary, Alberta

***Thomas Buchanan, C.A.****+
Calgary, Alberta

***Mike Shaikh, C.A.****
Calgary, Alberta

* members of the audit committee
\+ members of the reserve committee

## OFFICERS

***Steve Fitzmaurice, P.Eng.***
President and Chief Executive Officer

***Erik DeWiel, P.Land***
Vice President, Land and Business Development

***Randy Deobald, P.Geol.***
Vice President, Exploration

***Greg Turnbull, L.L.B.***
Secretary

## OFFICE

Suite 490, 734 – 7th Avenue S.W.
Calgary, Alberta T2P 3P8
***Telephone:*** (403) 262-1131
***Facsimile:*** (403) 313-4295
***Email:*** hawkoil@cadvision.com

## AUDITORS

***PricewaterhouseCoopers LLP***
Calgary, Alberta

## BANKERS

***National Bank of Canada***
Calgary, Alberta

## ENGINEERING CONSULTANTS

***Gilbert Laustsen Jung Associates Ltd.***
Calgary, Alberta

## REGISTRAR AND TRANSFER AGENT

***Computershare Investor Services***
Calgary, Alberta

## SOLICITORS

***Donahue LLP***
Calgary, Alberta

## STOCK EXCHANGE LISTING

***The Canadian Venture Exchange***
Trading Symbol: Class A Shares – **HWK.A**

| | |
|---|---|
| NGLs | natural gas liquids |
| bbls | barrels |
| mcf | thousand cubic feet |
| boe | barrels of oil equivalent (1bbl = 6 mcf) |
| boepd | barrels of oil equivalent per day |
| mbbls | thousand barrels |
| mmcf | million cubic feet |
| mboe | thousand barrels of oil equivalent |
| DCF | discount factor |
| $M | $ thousand |
| WTI | West Texas Intermediate |
| mcfd | thousand cubic feet per day |
| bopd | barrels of oil per day |
| WI% | working interest percent |
| mmbtu | million British thermal units |
| NAV | net asset value |

Designed and produced by Merlin Creative Group Inc.

HAWK OIL INC.

Suite 490, 734 – 7th Avenue S.W. Calgary, Alberta, Canada T2P 3P8
**Tel:** (403) 262-1131 **Fax:** (403) 313-4295 **E-mail:** hawkoil@cadvision.com
**Class A Shares** – HWK.A